GEORGIA INSTITUTE OF TECHNOLOGY OFFICE OF CONTRACT ADMINISTRATION

PROJECT ADMINISTRATION DATA SHEET

[x] ORIGINAL [ ] REVISION NO. ______

Project No. E-24-629 DATE 9/17/82

Project Director: Jane C. Ammons School/~~Lab~~ ISyE

Sponsor: NSF

Type Agreement: Grant No. ECS-8206612

Award Period: From 9/1/82 To 2/29/84 (Performance) 5/29/84 (Reports)

Sponsor Amount: $10,000 (Fixed amount) Contracted through:

Cost Sharing: $147 (E-24-360) GTRI/~~GIT~~

Title: New Engineering Faculty Research Incentive: Impact of Terminal Conditions in Long Range Generation Expansion Planning for Electric Utilities

ADMINISTRATIVE DATA

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Defense Priority Rating: NA

Security Classification: NA

RESTRICTIONS

See Attached NA Supplemental Information Sheet for Additional Requirements.

Travel: Foreign travel must have prior approval — Contact OCA in each case. Domestic travel requires sponsor approval where total will exceed greater of $500 or 125% of approved proposal budget category.

Equipment: Title vests with GIT; but none proposed

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SPONSORED PROJECT TERMINATION/CLOSEOUT SHEET

Date May 10, 1984

Project No. E-24-629

School/~~Lab~~ ISyE

Includes Subproject No.(s)

Project Director(s) Jane C. Ammons GTRI / ~~GIT~~

Sponsor National Science Foundation

Title "New Engineering Faculty Research Incentive: Impact of Terminal Conditions in Long Range Generation Expansion Planning for Electric Utilities"

Effective Completion Date: 2/29/84 (Performance) 5/29/84 (Reports)

Grant/Contract Closeout Actions Remaining:

- [ ] None
- [x] ~~Final Invoice or Final Fiscal Report~~ FCTR (Final)
- [ ] Closing Documents
- [x] Final Report of Inventions if positive
- [x] Govt. Property Inventory & Related Certificate if positive
- [ ] Classified Material Certificate
- [ ] Other

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E-24-629

NATIONAL SCIENCE FOUNDATION
Washington, D.C. 20550

FINAL PROJECT REPORT
NSF FORM 98A

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PART I—PROJECT IDENTIFICATION INFORMATION

1. Institution and Address	2. NSF Program	3. NSF Award Number
Georgia Institute of Technology Atlanta, GA 30332	NEFRI/ECSE	ECS-8206612
	4. Award Period From 9/20/82 To 9/20/83	5. Cumulative Award Amount $10,000

6. Project Title
Impact of Terminal Conditions in Long Range Generation Expansion Planning for Electric Utilities

PART II—SUMMARY OF COMPLETED PROJECT *(FOR PUBLIC USE)*

Long range planning for the electric power industry is a critical, but yet complex and expensive, task. This research has addressed an issue in electric utility generation strategic expansion planning. Planning decisions are based on results from intricate models which incorporate key aspects of the generating environment, including uncertainties describing the final portion of the planning horizon. The important nature of these terminal conditions and some of their interactions have been examined, and then tested using the computer implementation of a nonlinear mixed integer programming generation expansion model. Results were obtained in the form of solution sensitivity (expansion schedule changes) to aspects of demand representation and uncertainty, sensitivity of certain financial factors, and length of planning horizon. These results provide better understanding into the impact and complex nature of terminal conditions in long range generation expansion planning as well as insights into the tradeoffs between study length and desired forecast accuracy.

PART III—TECHNICAL INFORMATION *(FOR PROGRAM MANAGEMENT USES)*

1. ITEM *(Check appropriate blocks)*	NONE	ATTACHED	PREVIOUSLY FURNISHED	TO BE FURNISHED SEPARATELY TO PROGRAM: Check (✓)	Approx. Date
a. Abstracts of Theses	✓				
b. Publication Citations				✓	3/84
c. Data on Scientific Collaborators	✓				
d. Information on Inventions	✓				
e. Technical Description of Project and Results		✓			
f. Other *(specify)* Presentations at the Spring 1983 Nat'l TIMS/ORSA Conf., Chicago, IL and at the ORSA Energy Applications Group Conf., Washington, D.C., June 1983.		✓			

2. Principal Investigator/Project Director Name *(Typed)*	3. Principal Investigator/Project Director Signature	4. Date
Jane C. Ammons		1/13/83

An Analytic Study of Critical Terminal Conditions in Long Range Generation Expansion Planning for Electric Utilities

by

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An Analytic Study of Critical Terminal Conditions in Long Range Generation Expansion Planning for Electric Utilities

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Abstract

Long range planning of generation capacity is a complex and expensive task for electric utilities. Planning decisions are based on results from intricate models which incorporate key aspects of the generating environment, including uncertainties describing the final portion of the planning horizon. The critical nature of some of these terminal conditions have been examined analytically using the computer implementation of a nonlinear mixed integer programming generation expansion model.

An Analytic Study of Critical Terminal Conditions in Long Range Generation Expansion Planning for Electric Utilities

Introduction

Generation expansion planning (GEP) for electric utilities is a large scale and complex problem composed of many complicated and interacting issues. In overview, GEP can be stated as the selection of types and sizes of electric generating units to construct over a specified long range planning horizon while respecting limitations imposed by construction budgets, demand requirements, and reliability guarantees in order to minimize total discounted system cost. Models developed for the planning of investments in electric generating capacity are reviewed in the survey articles by Anderson [1972], Sassoon and Merrill [1974], and Knight, et. al. [1974].

Modeling approaches include linear programming (Anderson [1972], Masse' and Gibrat [1957], and Bessiere and Masse' [1964], mixed integer programming (Ammons [1982], Bloom [1983], Iwayemi [1975], Noonan and Giglio [1977], Rowse [1974], and Sawey and Zinn [1977]), nonlinear programming (Philips, et.al. [1969], Jenkins [1978], Bessiere [1970], and Paramantier [1979]), heuristics incorporating simulation (Booth [1971], Lansdowne, et.al. [1977], Marsh, et.al. [1975], and Jenkins and Joy [1974]), dynamic programming (Garver [1975], Henault, et.al. [1969], Irisari [1975], Morin and Jenkins [1981], Oatman and Hamant [1973], Peschon and Jamoulle [1975], and Peterson [1973]), and combinations of these (Beglari and Laughton [1975], and Farrar and Woodruff [1973]). Solutions of GEP problems is expensive: development of a viable model may cost up to 1.5 million dollars, and one subsequent extensive study may cost upwards of $300,000.

The specification of a forecasted scenario is required for each GEP study, with resulting impact on the model's solution. The scenario is prescribed by data requirements which include (1) fixed and operating costs characteristics for existing and proposed generation units; (2) time windows for commissioning, construction time and cost schedule for proposed units; (3) financial considerations including capital expansion budget, inflation rates, long and short term rates of return; (4) reliability characteristics of current and proposed units and corresponding system reliability requirements for each time period; and finally, (5) electricity demand forecasts including expected peak load per time period in the planning horizon.

Because the planning horizon may be of twenty to thirty years length, many of the forecasted quantities have uncertainty associated with them which greatly increases over the more distant future periods. Furthermore, different optimal solutions to GEP may be obtained for studies which differ only in the length of the planning horizon. In order to obtain the desired validity for solution results associated with the near future, studies of adequate length with appropriate terminal conditions must be run. However, the length of a study is a crucial determinant of its cost: as years are added to the planning horizon, data costs escalate linearly and computational requirements exponentially. Thus, terminal conditions have a critical impact on both the solution outcome and cost of GEP.

This paper presents the preliminary results for the analysis of terminal conditions in GEP. The next section develops inherent assumptions in GEP, followed by a discussion of uncertainty and complexity issues. Finally, their impact on "optimal" expansion schedules is presented.

Inherent Assumptions in Long Range GEP

In both the modeling and data construction phases of long range GEP, explicit as well as hidden assumptions are required. Typically assumptions are generated for such reasons as model feasibility, computational tractibility, convenience in data assimulation, etc. However, inherent in the GEP planning process are certain assumptions which are not necessarily explicit nor apparent. These assumptions are related to trends which continue past the end of the planning horizon: trends in such areas as costs, demands, technologies, and the potential environment.

Trends in costs and financial factors

Implicit in the modeling of long range GEP are critical assumptions concerning trends in costs and financial factors. As for costs, assumptions are required as to the behavior over time of the fixed costs associated with generating units. Also, the magnitude and functional characteristics of the unit operating costs must be specified for the planning horizon. Trends and relationships in both fixed and variable costs then implicitly extend past the end of the planning horizon.

Similarly, certain critical assumptions are required concerning the behavior of key GEP financial factors. Included in this category are trends in annual inflation rates, short and long term rates of return, magnitude of capital expansion budget and cash flow considerations, and construction costs and schedules. Again, trends in these assumptions extend past the given planning horizon.

Studies have tried to assess the impact of these assumptions on the outcome of GEP solutions. Galloway, et.al. [1969] investigated the resulting plant mix structure when the cost of fossil and peaking steam plants were varied while the nuclear and gas turbine costs were held fixed. Similarly, Felak, et. al. [1977] varied unit characteristics (fixed and operating costs) in a simulation study to assess resulting financial impact. Garver [1975] shows the relationship of GEP plant mix added over a 20 year horizon as a function of the inflation rate. Effect of the discount rate upon expansion schedules has been studied by Rowse [1979]. These studies demonstrate the critical nature of cost and financial assumptions in GEP.

Trends in demand

Similar to the inherent assumptions associated with trends in costs and financial factors are those related to demand for electricity. Implicit in GEP models are trends in peak load growth, load duration curve shape, load management, etc. -- trends which are assumed to extend past the end of the planning horizon. These trends are critical assumptions because demand is the driver of GEP problems, forcing expansions to be incurred.

Trends in technology

Related to the trends in costs, financial factors, and demand are trends in the technical environment of electric power generation. These issues include such items as future hydro availability, the licensing/operating/political environment for nuclear production, emergence of "new" sources such as solar, wind, tidal, etc., development of transmission modes with higher efficiencies, and coal/gas availabilities in the future. By inclusion or omission in the modeling or data determination steps of GEP, trends in technologies are inherent assumptions. Impact studies on just the reliability sector of GEP have been performed for solar (Jordan, et.al. [1977]) and nuclear (Panichelli, et.al. [1977]) technologies, for load management (Billinton and Alam [1978]), and for load shape dynamics (Jordan, et al. [1976]).

Length of planning horizon

In addition to inherent assumptions associated with trends in costs and financial factors, demand, and technologies, the selection of a planning horizon for GEP imposes other assumptions. Smaller planning horizons discriminate against units with large expansion costs because the benefits of their reduced operating costs may not be completely recovered within the planning horizon. A common assumption to overcome this problem uses the unit "extended costs" technique which assigns costs to each unit as though identical unit replications occur into an infinite extension period by assuming system status at the last year of the planning horizon will prevail forever (see Bloom [1978]). Often this assumption is required to assure computational tractability of the GEP model; however, the assumption has inevitable consequences upon unit selection, assumed trends, etc. Desired is the determination of "near planning horizons" as proposed for other simple planning problems (e.g., see Shapiro and Wagner [1967]).

Uncertainty and Complexity Issues

Interacting with the aforementioned trends and assumptions associated with planning horizon length are issues imposed by uncertainty and complexity with GEP. Planning for the future induces uncertainty into GEP; this uncertainty combined with intricate relationships between various aspects of GEP enforces it.

Uncertainty

Certainly one of the most challenging and possibly the most studied issues in GEP is the dynamic nature of the electricity generating environment. For a planning horizon of twenty to thirty years, who can predict with any certainty the correct scenario for the last portion of the planning horizon? Certain studies have focused on uncertainty in demand (Mount and Chapman [1978], Borison, et. al. [1983]), which is a critical segment because demand growth forces expansion in GEP. However, also important is the uncertainty associated with every other factor (cost, capacity, reliability, etc.) pertinent to GEP. And the interaction of the uncertainty associated with these factors is critical.

Factor interrelationships

Currently there is a shift in GEP approaches to recognize "the phenomena of interest today are the complex interactions" of various aspects of the planning problem (p. 7, Taylor [1982]. See also p. 89, Graves [1982]). For example, an upward shift in the inflation rate will have a definite impact on the outcome of the solution to GEP because of its interelationship with other factors. Typically inflation rates in GEP are applied in a discounting fashion with an upward shift in inflation rate. The capital expansion budget should inflate accordingly - but not necessarily uniformly as is commonly modeled. Similarly, construction costs, fixed costs, and production costs should increase; but, in reality, all units may not inflate identically. An upward shift in inflation has uncertain responses in the corresponding behavior of short and long term rates of return, peak load demand, load duration curve shape, trends in peak management, etc. Therefore, because of the interaction of various aspects of GEP, parametric changes in one factor induce nonobvious yet critical changes in others. This significant interaction is magnified when the effects of inherent uncertainty are considered.

Analysis

Assessing the impact of terminal conditions in long range GEP for electric utilities involves recognition of the inherent assumptions and factors mentioned above in both the modeling and computational planning stages. The modeling step requires capturing explicitly the factor(s) of interest - as in the modeling of demand uncertainty by Borison, et al. [1982]. However, realistically modeling all critical factors and their intricate interactions is such a challenge that traditionally empirical studies employing parametric variation have been substituted. Also, modeling effort in this area is dependent upon the GEP approach employed.

Some preliminary studies have been performed using data representative of a large Southeastern utility. The implementation is based upon the GEP mixed integer programming approach developed previously by the author (see Ammons [1982]). As a brief overview, the model is given as follows:

(P) Minimize $\sum_j f_j y_j + \sum_{ti} [\sum_j (V_{1jt} x_{jit}^2 + V_{2jt} x_{jit} + V_{3jt}) h_{it}]$ (1)

subject to $\sum_j x_{jit} \geq P_{it}$ for every i,t (2)

$L_{jt} y_j \leq x_{jit} \leq U_{jt} y_j$ for every i,j,t (3)

$\sum_j a_{jt} U_{jt} y_j \geq (1+m) P_t$ for every t (4)

$S_t - (1+r_t)\, S_{t-1} + \sum_j c_{jt} y_j = B_t$ for every t (5)

$LOLP_t(\{y\}) \leq LOLP_{t-max}$ for every t (6)

$\sum_{\{Jk\}} y_j = 1$ for every k (7)

$y_j \in \{0,1\}$ for every j (8)

$S_t \geq 0$ for every t (9)

where

y_j = zero-one valued integer variable indicating whether unit j is to be constructed

x_{jit} = operation level of unit j in interval i of period t

f_j = sum of discounted fixed costs (taxes, maintenance, etc.) associated with unit j over the planning horizon

$V_{\cdot jt}$ = discounted coefficients of quadratic production cost function for unit j in period t

h_{it} = number of hours in interval i of period t

P_{it} = power demand level in interval i of period t

L_{jt} = lower bound on production level on unit j in period t

U_{jt} = upper bound on production level on unit j in period t

a_{jt} = availability factor for unit j in period t, $0 < a_{jt} < 1$

m = portion of capacity reserve margin required when peak demand occurs

P_t = peak demand during period t

S_t = construction budget funds unused in period t, $S_0 = 0$

r_t = short term rate of return for period t

c_{jt} = construction funds required for unit j in period t

B_t = additional construction budget funds available in period t

$LOLP_t(\{y\})$ = the loss of load probability of system $\{y\}$ during period t

$LOLP_{t-max}$ = the maximum allowable loss of load probability during period t

$\{Jk\}$ = set of indices belonging to mutually exclusive projects, e.g., generalized upper bounds, system structural constraints.

P is a mixed integer nonlinear programming problem with a quadratic objective function and linear and nonlinear constraints. In the objective function (1), to be minimized is the discounted sum of fixed and operating costs associated with the expansion projects that are constructed. Operating costs are quadratic as experienced in industry (see Kirchmayer [1958]). Constraints (2) assure demand satisfaction for every interval of the load duration curve. [The load duration curve is a familiar representation for system demand during a time period, where demand level is shown as a function of amount of time the load is incurred during the period, a set of (h_{it}, P_{it}) points. For more detail, see Anderson [1972]]. Constraints (3) insure that unit operation meets capacity bounds. Reserve margin, or the assurance that enough capacity exists on the system to exceed peak demand when it occurs, is expressed in constraints (4). Construction budget limitations are explicit in (5). Constraints (6) represent the requirement that the system reliability, as measured by the loss of load probability, is guaranteed through the expansion schedule. Finally, constraints (7) prohibit a prospective unit from being initiated in more than one year.

Using a Benders' Decomposition approach, the model was implemented on a CDC 70/74-6400 as reported in the thesis. A base problem was constructed of 123 existing generating units and 25 potential expansion projects with 10 generalized upper bounds. Studies were performed over a planning horizon of 20 years. The base problem used twenty points to approximate the load duration curve points of (h_{it}, P_{it}). Criteria of 0.10 was used each year for loss of load probability, (0.05) * (peak load) for expected deficit, and 0.25 for reserve margin. For the base problem, the inflation rate for every time period was set at 0.10, with short term rate of return on surplus construction funds being 0.09 for each time period. The long term rate of return used to discount all costs to the present was set at 0.12. For all test problems the size of the base problem, the core requirements were approximately 82k decimal words.

Because demand is the forcing function in GEP, issues regarding its representation, associated uncertainty, etc. must be acknowledged. Aggregation of demand representation is a significant issue, especially when one considers the tradeoff between computational requirements and accuracy of forecasts at the end of the planning horizon. Sawey and Zoraster [1981] have reported the impact of demand aggregation on unit mix solution. For this base the problem, it was expected that as the number of points decreased, the total costs would be overestimated but that solution time would decrease. As Table 1 shows, the first anticipation was confirmed but the second was not. Upon examination of the results, the increase in solution time as the number of points decreased might be explained by convergence properties of the procedure. Identical optimal expansion schedules were obtained in each case.

However, no change in optimal expansion schedule was obtained when the short term rate of return in the base problem was varied from 0.00 to 0.09. Similar results were obtained for parametric variation of the discount rate. For levels of inflation higher than 10%, no feasible solution could be found to the original problem.

As anticipated, varying the length of the planning horizon yielded different optimal solutions. Table 2 shows the effect of varying the number of years in the planning cycle on execution time and solution value. As may be seen in Figure 1, the same construction schedule was obtained for planning horizon lengths of 9 anbd 10 years, while different schedules were obtained for runs of 14 and 20 years respectively. Choice of additions seemed to follow logical tradeoffs between fixed and variable costs while respecting construction budgets.

Summary

GEP is an expensive and complex task for electric utilities. Planning decisions are based on results from intricate analytical models which attempt to capture key components of the generating

Table 1. Effect of Varying the Number of Points Used to Represent the Load Duration Curve

NUMBER OF POINTS	5	10	BASE PROBLEM 20
Total executive time (cpu secs)	89.744	84.041	79.159
Optimal solution value(V_i)	48,764,542.	48,061,484.	47,752,229.
$(V_i-V_{20})/V_{20}$ * 100%	2.1%	0.6%	0.0%
Number of iterations run	3	3	3
Execution time requirments (cpu secs)			
Problem initialization	2.540	2.648	2.599
Initial feasible solution	37.638	38.369	35.460
Master problem solution	50.156	43.132	40.783
Subproblem solution	1.579	2.075	2.342

Table 2. Effect of Varying the Number of Years in the Planning Horizon

NUMBERS OF YEARS	9	10	14	BASE PROBLEM 20
Total execution time (cpu secs)	76.632	94.207	108.183	87.775
Optimal solution value (V_i)	$.22358912\times(10)^8$	$.24687944\times(10)^8$	$.34105119\times(10)^8$	$.4775229\times(10)^8$
Number of iteration run	1	1	3	3
<u>Execution time requirments (cpu secs)</u>				
Problem initialization	2.400	2.2400	2.5680	2.4240
Initial feasible solution	6.1350	8.1360	17.6400	39.7910
Master problem solution	69.0800	82.7630	81.5150	42.3920
Subproblem solution	0.2810	0.3207	1.5280	2.6320

environment. Included in these models are the inherent assumptions and crucial interrelationships described above, which impact critically on the "optimal" expansion schedule. Some of these factors may be explicitly included in the GEP model, but a more common approach is to perform parametric sensitivity analysis at a computational price. For illustration preliminary empirical results were presented for some simple one factor variation studies.

Acknowledgements

Dr. Leon F. McGinnis participated in initial discussions of the subject. Chris Berry performed some of the computational runs.

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